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STATE OF WASHINGTON

ENERGY FACILITY SITE EVALUATION COUNCIL

PO Box 43172 • Olympia, Washington 98504-3172

August 28, 2001

Subject: **Preliminary Approval of the Proposed Satsop Combustion Turbine Project (Satsop CT) Notice of Construction (NOC) and Prevention of Significant Deterioration (PSD) Permit.**

Dear Stakeholder:

In April 2001, Energy Northwest, Inc., and Duke Energy Grays Harbor, LLC., (jointly "Duke Energy") submitted an application for a Notice of Construction/ Prevention of Significant Deterioration (NOC/PSD) permit to the Energy Facility Site Evaluation Council (EFSEC), for the Satsop Combustion Turbine Project in Elma, Washington.

EFSEC has reviewed this permit application, including the Best Available Control Technology (BACT) evaluation, and has determined that Duke Energy has satisfactorily demonstrated that the approval of permit NOC/PSD No. EFSEC/2001-01 is justified. By letters to stakeholders and notice in a local newspaper, the Council has initiated the public comment period and anticipates taking action on Duke Energy's application at its October 8, 2001, regular council meeting.

Please find enclosed the Preliminary NOC/PSD Approval (No.EFSEC/2001-01) for your review and comment. A Fact Sheet and Public Notice are also enclosed for your information. Please provide comments to Council staff no later than Thursday, October 4, 2001.

Thank you for your cooperation.

Sincerely,

Irina Makarow
Energy Facility Site Specialist

Enclosures:
Public Notice
Fact Sheet
Preliminary Approval
Stakeholder Mailing List

c.c.: Stakeholder Mailing List

STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL
PO Box 43172 • Olympia, Washington 98504-3172

August 28, 2001

PUBLIC NOTICE

Notice of Public Comment Period - August 31, 2001 to October 4, 2001

Notice of Public Hearing - October 4, 2001, Elma, Washington

Announcement of intent to issue a Notice of Construction (NOC) and Prevention of Significant Deterioration Permit (PSD) Approval to discharge to air for the Satsop Combustion Turbine Project, Elma, Washington.

PROJECT DESCRIPTION:

On April 24, 2001, Energy Northwest and Duke Energy Grays Harbor, LLC, (jointly "Duke Energy") submitted an application for a Notice of Construction/Prevention of Significant Deterioration (NOC/PSD) permit and an evaluation of Best Available Control Technology (BACT) to the Energy Facility Site Evaluation Council (EFSEC or Council), for the Satsop Combustion Turbine Project (Satsop CT).

EFSEC is the state agency responsible for siting and permitting the construction and operation of thermal energy projects greater than 350 megawatts in the state of Washington. In May 1996, Energy Northwest was granted a Site Certification Agreement (SCA) by the Governor of Washington State to construct and operate the Satsop CT near Elma, Washington. In February 2001, The Energy Facility Site Evaluation Council authorized the addition of Duke Energy Grays Harbor, LLC, as a co-holder and co-permittee of the Satsop CT SCA. The SCA authorizes the project to begin construction within ten years of May 1996.

The Satsop CT is located in Grays Harbor County on a 20-acre site south of the Chehalis River, within an existing construction laydown area in the Satsop Development Park (formerly known as the Satsop Power Plant Site).

The Council has been delegated the authority under 40 CFR Part 52 to issue permits under the Prevention of Significant Deterioration (PSD) program. To comply with procedural requirements, the Council has contracted with the Washington Department of Ecology's Air Quality Program to prepare a draft PSD permit and fact sheet that will satisfy pertinent requirements, for Council and public consideration.

EFSEC issued a first NOC/PSD Permit (No. EFSEC/95-01) to Energy Northwest on September 12, 1996, for the purpose of constructing the Satsop CT project. After two successive 18-month extensions, NOC/PSD permit No. EFSEC/95-01 expired in March 2001.

The project consists of two General Electric gas combustion turbines (GE 7FA). Each unit will have a heat recovery steam generator (HRSG) and supplementary duct burner. Other major components of the project include one steam turbine generator, one auxiliary boiler, and one forced draft cooling tower system. The proposed facility will use natural gas fuel only. This power plant is rated at 600 Megawatts (MW) nominal, with a maximum output of 650 MW.

The Satsop CT facility will be a major new source of air pollution because it will emit more than 100 tons per year of nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter (PM_{10}). Emissions of NO_x, CO, SO_2, VOC, PM_{10}, and H_2SO_4 are subject to regulation under the PSD program.

Based on the April 2001 submittal to EFSEC, Duke Energy proposes to control nitrogen oxides (NO_x) emissions from the gas turbines and heat recovery steam generators to 2.5 ppmvd by the use of dry-Low NO_x combustors in combination with Selective Catalytic Reduction (SCR). An oxidation catalyst is proposed to control carbon monoxide (CO) emissions to 2 ppmvd, and volatile organic compounds (VOC) emissions to 2.78 ppmvd. Burning pipeline quality natural gas will control particulate matter emissions to 16.3 lbs. per hours, sulfur dioxide emissions to 0.11 ppmvd, and sulfuric acid to 1.3 lbs. per hour. Toxics-BACT for ammonia will consist of selective catalytic reduction with an emission limit if 5 ppmvd.

Emissions from the auxiliary boiler will be controlled by a combination of Flue Gas Recirculation and low NO_x burners for controlling NO_x emissions to 30 ppmvd. The operation of the auxiliary boiler will be limited to 500 hours per year.

PRELIMINARY DETERMINATION:

After reviewing the April 2001 NOC/PSD application and the accompanying BACT evaluation submitted by Duke Energy, the Council has made a preliminary determination that all requirements for PSD and New Source Review are satisfied, and that if the preliminary draft permit were approved, the emission units would comply with all applicable federal and Washington state new source performance standards, in accordance with the provisions of Chapters 463-42-385 and 173-400, and -460 of the Washington Administrative Code (WAC) and the Code of Federal Regulations (CFR), 40 CFR Parts 52.21 and 60.

The Council has determined that allowable emissions from the proposed emission units, in conjunction with all other applicable emission increases or reductions (including secondary emissions) would not cause or contribute to violation of any ambient air quality standard or any applicable maximum allowable increase over the baseline concentration in any area.

Modeling indicates that that there would be no significant impacts resulting from pollutant deposition on soils and vegetation in the Class I areas: Alpine Lakes Wilderness, Glacier Peak Wilderness, North Cascades National Park, Olympic National Park, and Pasayten Wilderness, the proposed Class I area, the Mt. Baker Wilderness. Ambient impact analysis indicates that it is very unlikely that the proposed emissions would cause significant degradation of regional visibility, or impairment of visibility in any Class I area. The Satsop CT Project is unlikely to have a significant impact on vegetation, soil, and aquatic resources in Class I or Class II.

A final determination on this PSD permit approval will not be made until after the 30-day public comment period, and all comments received pursuant to this notice have been considered.

PUBLIC COMMENT:

This notice serves as the Council's official notification that the draft PSD permit has been issued, and is available for public inspection and comment. It also serves as notice that members of the public and interested parties have an opportunity to submit written comments to the Council on the draft PSD permit.

The draft permit NOC/PSD No. EFSEC/2001-01 and the corresponding Fact Sheet (a supplement to the permit to provide more detailed information) are available for review during the public comment period at the locations below. Copies of these documents are available free of charge upon request from EFSEC by contacting Irina Makarow at (360) 956-2047.

Copies available for public reference and copying:

Washington Energy Facility
Site Evaluation Council
925 Plum Street SE, Building 4
P.O. Box 43172
Olympia, WA 98504-3172
8:00 a.m. to 5:00 p.m. weekdays
Phone (360) 956-2121

Washington State Department of Ecology
300 Desmond Drive
Lacey, Washington.
8:00 a.m. to 4:30 p.m. weekdays
Please contact Alex Piliaris at
(360) 407-6811.

Copies available for public reference:

W.H. Abel Memorial Library
125 Main Street South
Montesano, WA 98563-3794

In electronic format on the internet:

The EFSEC web site at
http://www.efsec.wa.gov/satsop/psd.htm

The public comment period will extend from **August 31, 2001** to **October 4, 2001**. Interested persons may review the documents and submit written comments regarding the proposed permit. Written comments must be submitted to the Energy Facility Site Evaluation Council at the address below. Written comments will be accepted through the end of the October 4, 2001, public hearing.

Written comments should be submitted to the attention of:

Irina Makarow
EFSEC
P.O. Box 43172
Olympia, WA 98504-3172

All persons, including the applicant, who believe this approval or any condition of the proposed approval is inappropriate must raise all reasonably ascertainable issues and submit all reasonably available arguments supporting their position in writing by the end of the comment period. Any supporting materials which are submitted shall be included in full and may not be incorporated by reference, unless they are already part of the administrative record for this proposed approval or are generally available reference material.

PUBLIC HEARING:

A public hearing on this matter will be held on **Thursday, October 4, 2001,** beginning at **7:00 p.m.**, at the **Elma High School Commons, 1011 E. Main Street, Elma, Washington, 98541**.

Any affected party may submit a written request to the Council to provide oral comments at the public hearing. Requests must be submitted to the Council during the public comment period. The request must indicate the interest of the party and identify specific concerns. The Council will limit the hearing only to the matters specifically related to permit conditions. The hearing will be conducted in accordance with the Administrative Procedures Act, Chapter 34.05 Revised Code of Washington.

ADDITIONAL INFORMATION:

Please bring this Notice to the attention of persons who you know would be interested in this matter.

Once the final determination is made, a copy of the Council's final determination regarding the proposed extension will be filed for review at the locations above. Within 30 calendar days after the final decision has been issued, any person who commented on the draft approval may petition the EPA Administrator, under 40 CFR 124.19, to review any condition of the decision. Any person who failed to file comments or failed to participate in the public hearing on the draft may petition for administrative review only to the extent of the changes from the draft to the final approved decision.

For more information, or if you have special accommodation needs, contact Irina Makarow at (360) 956-2047 (Voice) or (360) 586-4224 (TDD).

Allen J. Fiksdal

By: Allen Fiksdal, EFSEC Manager
PO Box 43172
Olympia, Washington 98504-3172

Washington State
ENERGY FACILITY SITE EVALUATION COUNCIL

Satsop Combustion Turbine Project, Elma, WA
Preliminary Approval - Notice of Construction/Prevention of Significant
Deterioration Permit No. EFSEC/2001-01

Stakeholders

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Dr. Sodhi
Director, Natural Resources
Chehalis Confederated Tribes
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FACT SHEET FOR
PREVENTION OF SIGNIFICANT DETERIORATION PERMIT
Satsop Combustion Turbine Project
Elma, Washington
August 28, 2001

1. INTRODUCTION

1.1 THE PSD PROCESS

The Prevention of Significant Deterioration (PSD) procedure is established in Title 40, Code of the Federal Regulations (CFR), 40 CFR Part 52.21. Federal rules require PSD review of all new or modified air pollution sources that meet certain criteria. The objective of the PSD program is to prevent serious adverse environmental impact from emissions into the atmosphere by a proposed new source. The program limits degradation of air quality to that which is not considered "significant." It also sets up a mechanism for evaluating the effect that the proposed emissions might have on environmentally related areas for such parameters as visibility, soils, and vegetation. PSD rules also require the utilization of the most effective air pollution control equipment and procedures, after considering environmental, economic, and energy factors.

EFSEC is the state agency responsible for siting and permitting the construction and operation of thermal energy projects greater than 350 megawatts in the state of Washington per Chapter 463 of the Washington Administrative Code (WAC), and Chapter 80.50 of the Revised Code of Washington (RCW).

1.2 THE PROJECT

Energy Northwest and Duke Energy Grays Harbor, LLC, (jointly " Duke Energy") are proposing to construct and operate a natural gas combined cycle power generation facility located near the town of Elma, Washington. The name of the proposed facility is the Satsop Combustion Turbine Project (Satsop CT). This power plant is rated at 600 Megawatts (MW), nominal, with a maximum output of 650 MW.

In May 1996, Energy Northwest was granted a Site Certification Agreement (SCA) by the Governor of Washington State to construct and operate the Satsop CT near Elma, Washington. In February 2001, the Energy Facility Site Evaluation Council authorized the addition of Duke Energy Grays Harbor, LLC, as a co-holder and co-permittee of the Satsop CT SCA. The SCA authorizes the project to begin construction within ten years of May 1996.

The Satsop CT Project received a PSD permit in 1996. After two consecutive permit extensions in March 1998 and September 1999, the PSD permit expired prior to construction of the facility. Duke Energy submitted an application for a new PSD permit in April 23, 2001; this application was deemed complete in August 2001.

This project consists of two General Electric gas combustion turbines (GE 7FA). Each unit will have a heat recovery steam generator (HRSG) and supplementary duct burner. Each turbine will have a maximum rating of 1,671 MMBtu/hr and each supplementary duct burner will have a maximum rating of 505 MMBtu/hr. Other major components of the project include one steam turbine generator, one auxiliary boiler, and one forced draft cooling tower system. The proposed facility will use natural gas fuel only.

Air for the two turbines will be compressed and mixed with natural gas in the combustion chambers of the combustion turbine generators. Exhaust gas from the combustion chambers will be expanded through power turbines to recover energy released from combustion. The gas-fired turbines are connected to electric generating units. Heat from the exhaust will be reheated by the duct burner, and will be recovered in a HRSG which is designed to produce steam at pressures required to extract the maximum energy from the turbine exhaust gas and produce the maximum power from steam turbines connected to electric generators. This arrangement is called a combined cycle gas turbine.

The Satsop CT facility will be a major new source of air pollution because it will emit more than 100 tons per year of nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter (PM_{10}). Emissions of NO_x, CO, sulfur dioxide (SO_2), volatile organic compounds (VOC), particulate matter (PM_{10}), and sulfuric acid (H_2SO_4) are subject to regulation under the PSD program.

Duke Energy is proposing to control nitrogen oxides emissions from the gas turbines and heat recovery steam generators by the use of dry-Low NO_x combustors in combination with Selective Catalytic Reduction (SCR). An oxidation catalyst is proposed to control carbon monoxide and volatile organic compound emissions. Burning pipeline quality natural gas will control particulate matter, sulfur dioxide and sulfuric acid to low levels.

2. DETERMINATION OF BEST AVAILABLE CONTROL TECHNOLOGY

2.1 DEFINITION

By law, all new sources are required to utilize Best Available Control Technology (BACT). BACT is defined as an emission limitation based on the most stringent level of emission control available or applied at an identical or similar source (40 CFR 52.21(b)(12)). Satsop CT must achieve this level of control or prove it is technically or economically infeasible before a less stringent level of control is allowed.

2.2 BACT FOR GAS TURBINE/HEAT RECOVERY STEAM GENERATOR SYSTEMS

2.2.1 NITROGEN OXIDES CONTROL

Federal new source performance standards (40 CFR 60.330 Subpart GG) limit nitrogen oxides emissions from stationary gas turbines burning natural gas to 119 parts per million by volume dry (ppmvd) corrected to 15 percent oxygen. Sulfur content of fuel containing more than 0.8 percent sulfur is prohibited. Federal new source performance standards for electric utility units (40 CFR 60.40a Subpart Da) apply to the gas-fired duct burners for the proposed Satsop CT Project. Under this NSPS, particulate, sulfur dioxide and nitrogen dioxide emissions from the duct burners are limited to 0.03, 0.02, and 0.02 pounds per million Btu, respectively. At the proposed maximum firing rate of 505 million Btu per hour, these limits translate to 15.2 pounds per hour of particulate matter, 100.8 pounds per hour of SO_2 and

100.8 pounds per hour of NOx.

The proposed NOx concentration for each Satsop CT Project (power generation facility) is 2.5 ppmvd at 15 percent O2 at each stack, which satisfies Subpart GG requirements. Proposed duct burner emissions rates are 5.5 lb/hr for particulate matter, 0.31b/hr for sulfur dioxide, and 4.9lb/hr for nitrogen oxides which satisfy Subpart Da requirements.

2.2.1.1 CONTROL TECHNOLOGIES CONSIDERED FOR NO_X REDUCTION:

Combustion Modifications:

1. Steam/Water Injection: Steam/Water Injection has been widely used as a gas turbine NO_x emission control. Steam or water is injected into the combustion zone to lower the peak combustion zone flame temperature. High-purity water must be used to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms as water injection to reduce the peak flame temperature. Typical injection rates range from 0.3 to 1.0 pounds of water and 0.5 to 2.0 pounds of steam per pound of fuel. The NOx reduction efficiency of the steam/water injection to reduce NO_x emissions depends on turbine design. For a given turbine design, the maximum water/fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine. Different turbine designs have different maximum water/fuel ratios.

2. Dry Low-NO_x Combustor: The modern, dry low- NO_x combustor technology is typically a three-stage, lean, premix design, which utilizes a central diffusion flame for overall flame stabilization. The lean, premixed approach burns a lean fuel-to-air mixture for a lower peak combustion flame temperature resulting in lower thermal NO_x formation. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and the other stages at higher loads. This provides efficient combustion at lower temperature, throughout the combustor-loading regime. The dry low-NO_x combustor reduces NO_x emissions by up to 87 percent over a conventional combustor.

3. XONON: This technology provides combustion modifications by lowering the peak combustion temperature to reduce formation of NO_x while also providing further control of CO and unburned hydrocarbon emissions that other NO_x control technologies cannot provide. Most gas turbine emission control technologies remove air contaminants from the exhaust gas prior to release to the atmosphere. In contrast, the overall combustion process in the XONON system is a partial combustion of the fuel in the catalyst module, followed by completion of the combustion downstream of the catalyst. In the catalyst module, a portion of the fuel is combusted without a flame to produce a hot gas. XONON is an innovative technology that is currently commercialized on smaller projects operating below 10 MW simple-cycle pilot facility. The manufacturer of XONON has been conducting field tests to verify the emission performance of this technology. However, the current field tests are being run using 10 MW engines and smaller. This technology has not been proven nor is it commercially available on a turbine within an equivalent size range as that proposed for the Satsop CT Project. Therefore, this technology is deemed technologically infeasible, until further test data show the application is successful on larger engines.

Post- Combustion Controls

1. SCONOx: This technology is a relatively new post-combustion control system that uses a coated catalyst installed in the flue gas to remove both NOx and CO without a reagent such as ammonia. The NOx emissions are oxidized to NO2 and then absorbed onto the catalyst. A diluted steam of hydrogen gas is passed through the catalyst periodically to de-absorb the NO2 from the catalyst and reduce it to N2 prior to exit from the stack. CO is oxidized to CO2 and exits the stack, and VOC is reduced as well. This control technology was utilized on a small combustion turbine, approximately 28 MW, in Vernon, California in December 1996. In Washington, SCONOx has not been proven to be economically feasible for projects of the size proposed for the Satsop CT Project. The Satsop CT Project is proposing to use proven pollution control technologies that achieve emission rates equivalent to those targeted with SCONOx.

2. Selective Catalytic Reduction: Selective catalytic reduction (SCR) is a post-combustion NO_x control technology. In SCR, ammonia (NH3), diluted with air or steam, is injected into the flue gas, upstream of a catalytic reactor. The catalyst bed operates at temperatures between 600 and 800 F, depending on the catalyst. On the catalyst surface, the NH3 reacts with NO_x to form molecular nitrogen and water.

   The primary variable affecting NO_x reduction is temperature. If operating below the optimum temperature range, the catalyst activity is reduced, allowing unreacted NH3 to slip into the exhaust stream. If operating above the optimum temperature range, NH3 is oxidized, forming additional NO_x, and the catalyst may suffer thermal stress damage. SCR cannot be used effectively on waste gas streams that contain large amounts of particulate matter or sulfur dioxide. Particulate deposits on the catalyst surface degrade the catalyst and prevent NOx reduction from occuring.

3. Selective Non-Catalytic Reduction (SNCR): This technology is similar to the SCR process, SNCR uses ammonia or a urea-based reagent to chemically react with the NO_x in the exhaust gas steam, forming N2 and steam. Because no catalyst is used for SNCR, the temperature required for the reaction ranges from 1,600 F to 1,750 F for ammonia, and from 1,000 F to 1,900 F for urea-based reagents. The NO_x conversion efficiency declines below these temperature ranges and the concentration of unused reagent in the emissions increases. Above these temperature the reagent will tend to react with the excess oxygen in the exhaust gas instead of the NO_x forming additional NOx. At optimum temperature, NO_x destruction efficiencies range from 75 percent to greater than 90 percent. However, SCNR is very dependent on adequate mixing and adequate residence times.

2.2.1.2. EVALUATION OF TECHNICAL AND ECONOMIC FEASIBILITY FOR NITROGEN OXIDES CONTROL

This section addresses the technical and economic feasibility of the **NO_x control** technologies described above with respect to the Satsop CT Project.

Combustion Modifications

The technology ranking (for combustion modification) from highest (most effective) to lowest for the

Satsop CT Project is as follows:

1. XONON
2. Dry low- NOx combustion
3. Water/steam injection

1. XONON: Catalytica has been conducting field tests to verify the emissions performance of the XONON technology. However, the current field tests are being run using a 1.5 MW engine (emitting less than 3.0 ppm NO_x and less than 10 ppm CO), which is the first use of technology of the XONON technology on a full- scale engine. Installation of this combustion technology on a GE 10 turbine is scheduled to start sometime in fall of 2001. Because this innovative technology has not been proven on a turbine within an equivalent size range as that proposed for the Satsop CT Project, this technology is deemed technologically infeasible, until further results show the application is successful on larger engines.

2. Dry Low-NO_x Combustor: Dry Low NO_x combustor will be an integral part of the PG units designed for the Satsop CT Project. This technology is guaranteed by the manufacturer to reduce NO_x emissions from the PG units to 9 ppmvd for natural gas firing. This technology will not satisfy current regulatory requirements without the addition of a post-combustion control

3. Steam/Water Injection: This technology is capable of reducing exhaust gas NO_x concentrations from natural gas firing to a concentration of 25 ppmvd, assuming combustion is at 15 percent oxygen. This technology will not satisfy regulatory requirements without the addition of a post-combustion control. This technology could be implemented on the Satsop CT Project.

Post-Combustion Control

The technology ranking (for post combustion) from highest (most effective) to lowest for the Satsop CT Project is as follows:

1. SCONOx
2. SCR
3. Selective Non-Catalytic Reduction

1. SCONOx: This technology has not been proven technically feasible for projects of the size proposed with the Satsop CT Project. However, this technology has been utilized satisfactorily for several years in two facilities, providing strong evidence that the process is technically feasible at small power plants. Only one large source in California has a permit which includes SCONOx as a control for three of four turbines. The fourth turbine can be controlled using either SCONOx or SCR. This facility will be in an ozone nonattainment area. Therefore, SCONOx is considered technically feasible but unproven for large power plants such as the Satsop CT Project. Cost data submitted to Duke Energy by SCONOx's vendor indicates that annual costs would be $3,785,257 million per turbine resulting in an incremental cost of $12,870 per ton of nitrogen oxides removed. Further, the cost for the SCR system is $4,816 per ton of NOx removed while the cost for the SCONOx system is $14,844 per ton of NOx removed(SCONOx also removes CO and VOC). The costs for SCONOx are

unreasonably high and the Satsop CT Project is proposing to use proven pollution control technologies that achieve an emission rate equivalent to those targeted with SCONOx.

2. Selective Catalytic Reduction: This technology is readily available for many applications, including combustion turbines. Typically, SCR is an integral element of the HRSG unit on combined cycle plants, where the exhaust gas is at the optimum temperature. The Satsop CT Project is proposing to use proven pollution control technologies that achieve emission rates of 2.5 ppmdv, which is approximately equal (the SCONOx vendor will grantee nitrogen oxides emissions not to exceed 2.0 ppmdv when natural gas is burned) to those targeted with SCONOx.

   SCR technology has been applied successfully for NO_x emission control since at least the early 1980's. Its technical feasibility is without question. Consequently, the choice between SCONOx and SCR rests heavily on cost effectiveness. Cost data submitted by Duke Energy for SCR are $1,227,962 per turbine or $4,816 per ton of NO_x reduction under full plant operation.

3. Selective Non-Catalytic Reduction: This technology is commercially available for many applications, but has not fared well in the market place. There are no recent applications of SNCR to combustion turbines. Furthermore, adequate performance of SNCR is very dependent on residence time, which is very short in the high flow rate exhaust of a turbine. As indicated in the Ract/Bact/Lear Clearinghouse determination search, SNCR is not demonstrated on turbines. Consequently, this technology is considered technically infeasible for this project.

Table 1. Provides a comparison of estimated control efficiencies for dry low- NO_x combustors and dry low- NO_x combustors with SCR.

TABLE 1
NOx EMISSION CONTROL EFFICIENCIES FOR EACH PGU AT SATSOP CT PROJECT

Emission Control Mechanism	CT Load	NO_x Emission Concentration (ppmvd @ 15% O2 and ISO)	NO_x Emission Rate (lb/hr)	Control Efficiency (Ratio to NOx Control
Conventional Combustor	Base	72.4	628.8*	
Dry Low NO_x(DLN) Combustor	Base	9**	78.1	87.6%
DLN w/SCR (with duct burner firing)	Base	2.5**	21.7**	96.5%

*Based on AP-42, Section 3.1, Table 3.1-1, April 2000, for turbine emissions and AP-42, Section 1.4, Table 1.4-1, September 1998, for duct burner emissions
**Emissions provided by General Electric and Duke/Fluor-Daniel.

2.2.1.3. BACT DETERMINATION

The environmental, energy and economic impacts of the above-ranked NO_x control technologies for the

Satsop CT Project are presented in this section. The highest ranked NO_x control is a combination of the dry low-NO_x combustors and SCR with an emission limit of 2.5 ppm.

Dry Low-NOx Combustors

1. Environmental Impacts: DLN (combustors) pose no identified negative environmental impacts when implemented on a GE 7FA combustors turbine. The emission reduction is the same as with steam injection, but without increasing CO emissions and water consumption.
2. Energy Impacts: There is no energy impact associated with Dry Low NO_x combustors when firing natural gas. The power output is the same as the output for a turbine with conventional combustors.
3. Economic Impacts: An assessment of economic impacts was not performed for Dry Low NO_x combustors because the Dry Low-NO_x combustors are an integral part of the GE 7FA combustion turbine.

SCR

1. Environmental Impacts: There are several environmental concerns associated with SCR control technology. The primary concern is that ammonia emissions are released when ammonia passes through the catalyst unused, and is exhausted through the stack. Ammonia slip may range from less than 5.0 ppm to 50.0 ppm during start-ups.

   Ammonia is most frequently shipped by highway or rail and the potential exists for a spill due to an accident, although the likelihood is low. Spills may occur during the transfer of aqueous ammonia from one container to another. Another negative side effect is the formation of SO3 from some of the SO2 entering the system in the exhaust stream. SO3 reacts with the unused ammonia in the exhaust stream to produce ammonium sulfate and ammonium bisulfate salts. These salt particles create corrosion problems within the heat recovery system and will require more maintenance at the HRSG.

2. Energy Impacts: The presence of the SCR system in the HRSG introduces added resistance to the turbine exhaust, which increases the combustion turbine backpressure. This results in more energy being expended to force air through the turbine, thus reducing power output.

3. Economic Impacts: Each SCR system is estimated to cost $1,227,962 resulting in a $4,816 cost per ton of NOx removed which is within the range of previous BACT cost effectiveness determinations.

2.2.1.4. SELECT BACT

Although there can be adverse effects using SCR control technology, previous BACT determinations in Washington State indicate that SCR is required to reduce NOx emissions to levels of 2.5 ppmvd or lower. The Satsop CT Project is located in an attainment area for ozone, and the implementation of this technology should not significantly contribute to ozone levels. **EFSEC agrees with Satsop CT Project's evaluation and determines BACT for NOx to be selective catalytic reduction.**

The proposed NOx emission limits are shown in Table 2.

TABLE 2
PROPOSED BACT NOx EMISSION LIMITS FOR EACH PGU*

Pollutant	Emissions (ppmvd) at 15% O2	Emissions (lb/hr)
NOx	2.5	21.7

*These emission limits apply to CT loads>50%. Above data provided by General Electric and Duke/Fluor-Daniel.

2.2.1.5. MONITORING AND REPORTING REQUIREMENTS

NOx emissions and exhaust gas flow rate or velocity from each exhaust stack shall be measured and recorded by a continuous emission monitoring system that meets the requirements of 40 CFR 60, Appendix F.

2.2.2 CARBON MONOXIDE CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for Carbon Monoxide (CO) from gas turbines.

2.2.2.1. CONTROL TECHNOLOGIES CONSIDERED FOR CO REDUCTION:

Control Options Considered in order of stringency:

- SCONOx (90% carbon monoxide reduction)
- Catalytic Oxidation (80% carbon monoxide reduction)

1. SCONOX: The most stringent means to control carbon monoxide (CO) is SCONOx. SCONOx reduces CO emissions at the same time as it reduces NOx. SCONOx reduces CO emissions by catalytically oxidizing the CO to carbon dioxide. If SCONOx were to be chosen as the emissions control technology, CO emissions should be reduced from 9 ppmdv uncontrolled to 1 ppmdv when firing natural gas. This is a 210 tons per year CO reduction for both turbines at fully permitted operation. As mentioned in this fact sheet, the SCONOx process is substantially more expensive than the SCR process for NOx reduction. Due to SCONOx 's ability to reduce multiple pollutants, the excess cost can be applied to a CO reduction BACT cost effectiveness determination. The excess in annual cost of SCONOx over SCR for NOx reduction is $2,557,295. This is $13,660/ton applied as the CO and the VOC reduction cost. The above information was taken from similar size project recently permitted in Washington.

2. Catalytic Oxidation: The most stringent means to control carbon monoxide is catalytic oxidation. The hot exhaust gas passes through a catalyst section where oxygen in the gas stream is reacted with CO to produce CO_2. Additionally, minor quantities of VOCs are also reacted to form CO_2 and water. The use of a CO catalyst exerts an energy penalty on the turbine system, due to the increased backpressure on the turbine from the presence of the catalyst section.

2.2.2.2. CO EMISSION LIMITS AND MONITORING REQUIREMENTS

The Satsop CT Project chose the use of a Catalytic Oxidation in conjunction with combustion controls to control the emissions of CO.

EFSEC agrees that catalytic oxidation in addition to combustion controls is BACT for CO control. CO emissions from each CT/HRSG exhaust stack of the project shall not exceed 2 ppmvd (10.6 lb/hr with duct firing and 8.2 lb/hr without duct firing at 100% CT load) at 15% oxygen on an hourly average when pipeline quality natural gas is burned.

Each stack will be equipped with continuous CO monitoring that meets the requirements of 40 CFR 60, Appendix F. The provision of continuous monitoring effectively makes the CO limit more stringent than periodic manual compliance testing. A continuous emission monitoring system (CEMS) will be required to insure 24-hour per day compliance. The proposed CO emission limits are shown in Table 3.

TABLE 3

PROPOSED BACT CO EMISSION LIMITS FOR EACH PGU*

Pollutant	Emissions (ppmvd) at 15% O2	Emissions (lb/hr)
CO	2	10.6

* Satsop Combustion Turbine Project PSD Application

2.2.3 SULFUR DIOXIDE CONTROL

Federal new source performance standards (40 CFR 60.330 Subpart GG) for turbines limit sulfur dioxide emissions to 150 ppmvd at 15 percent O_2 and by limiting sulfur content of the natural gas to less than 0.8 percent by weight. The proposed Satsop CT Project will use pipeline quality natural gas with sulfur content of 0.2 gr/100dscf.

2.2.3.1. CONTROL OPTIONS CONSIDERED

- Low-sulfur fuel
- Wet Scrubbing
- Dry Scrubbing

1. Low-sulfur fuel: Natural gas is considered a clean fuel containing only trace amounts of sulfur. Proposed emission rates for SO2 are based on a sulfur content of 0.2 gr/100 scf natural gas, an appropriate and accepted value for the natural gas to be used at Satsop CT.

2. Wet Scrubbing: Exhaust gas is passed through a spray tower scrubber and a liquid phase alkaline reagent reacts with the SO_2 generating various end products. The resulting exhaust stream must be cooled and passed through a mist eliminator. The removed water is recycled and the exhaust is directed to a stack. Wet scrubbers are used mainly in coal-fired boilers and in some chemical plants and kraft pulp mills. Wet scrubbers have not been used as controls for combustion gas turbines because the pressure drop may cause severe operational constraints on power generation capability.

3. Dry Scrubbing: Dry scrubbing is also used mainly by large coal-fired boilers and has not been used to control GE turbine emissions. Dry scrubbing creates excessive pressure drop constraints on turbines due to the addition of a particulate device.

2.2.3.2. SO_2 EMISSION LIMITS AND MONITORING REQUIREMENTS:

The Satsop CT Project will be using pipeline quality natural gas with very low sulfur levels. The permitted sulfur dioxide emission using pipeline quality natural gas is calculated to be 0.11 ppmdv (measured at 15% oxygen). Sulfur dioxide emissions from each PGU exhaust stack shall not exceed 1.3 lb/hr.

Emission monitoring for SO_2 will be achieved by the following means: 1) fuel flow monitoring and total fuel sulfur content reporting that meets the requirements in 40 CFR 75, and 2) conducting source testing for sulfur dioxide once per month for the first year of operation at each PGU exhaust stack. If test results demonstrate compliance with permit conditions, subsequent stack testing for sulfur dioxide can be reduced to once per year.

EFSEC agrees that the use of pipeline quality natural gas is BACT for SO_2. SO_2 emissions from each PGU's exhaust stack of the project shall not exceed 1.3 b/hr. The proposed emission limits are shown in Table 4.

TABLE 4.

PROPOSED BACT SO2 EMISSION LIMITS FOR EACH PGU*

Pollutant	Emissions (ppmvd) at 15% O2	Emissions (lb/hr)
SO2	0.11	1.3

* Satsop Combustion Turbine Project and PSD Application

2.2.4 VOLATILE ORGANIC COMPOUNDS (VOC)

There are no federal new source performance standards for VOC emissions from gas turbines (40 CFR 60.330 Subpart GG) or duct burners (40 CFR 60 Subpart Da).

2.2.4.1. CONTROL OPTIONS CONSIDERED:

- Catalytic Oxidation
- Thermal Oxidation
- Combustion Controls
- Carbon Adsorption
- Condensation
- Absorption

1. Catalytic Oxidation: The most stringent means to control VOCs is catalytic oxidation using a catalyst to effect oxidation at the lower temperatures of the exhaust gases. The use of a catalytic oxidation to oxidize carbon monoxide will provide air quality improvements well below the PSD significant impact levels.

2. Combustion Controls, Thermal Oxidation, Carbon Adsorption, Condensation and Absorption: Good combustion controls that provide for the lowest NO_x and CO emissions also provide for a minimal quantity of VOCs to be emitted from the process. Thermal oxidation uses a flame to incinerate the pollutants. Organic contaminants are removed from gas streams using adsorption, condensation and absorption technologies. These technologies have better efficiencies when used to control exhausts containing large concentrations of hydrocarbons.

EFSEC agrees with the Satsop CT Project's evaluation and determines BACT for VOC to be use of natural gas and oxidation catalyst. Volatile organic compound (VOC) emissions from each PGU's exhaust stack shall not exceed 8.4 lb/hr under base load with duct firing and 2.9 lb/hr without duct firing. The proposed VOC emission limits are shown in Table 5.

TABLE 5.
PROPOSED BACT VOC EMISSION LIMITS FOR EACH PGU*

Pollutant	Emissions (ppmvd) at 15% O2	Emissions (lb/hr)
VOC	2.78	8.4

* Satsop Combustion Turbine Project PSD Application

2.2.4.2. VOC EMISSION LIMITS AND MONITORING REQUIREMENTS:

EPA Reference Method 25B, or an equivalent method agreed to in advance by EFSEC , shall determine initial and continuing compliance.

2.2.5 PARTICULATE AND PM_{10} CONTROL

There are no federal new source performance standards (40 CFR 60.330 Subpart GG) for particulate or for particulate matter less than 10 microns (PM_{10}) emitted from gas turbines. Duct burners subject to 40 CFR 60 Subpart Da are limited to 0.02 lb/mmBtu.

State standards limit particulate emissions to (0.10 gr/dscf) at 7% O_2 (WAC 173-400-100-060).

2.2.5.1. CONTROL OPTIONS CONSIDERED:

Clean fuels and good combustion control.

2.2.5.2. PM_{10} EMISSION LIMITS AND MONITORING REQUIREMENTS

EFSEC agrees with the Satsop CT Project that good combustion practice and using only pipeline quality natural gas constitute BACT for PM_{10} emissions. PM_{10} emissions from each PGU exhaust stack of the project shall not exceed 16.3 lb/hr with duct firing and 10.3 lb/hr without duct firing. The proposed particulate emissions for the Satsop CT Project are shown in Table 6.

TABLE 6.

PROPOSED BACT FOR PARTICULATE EMISSION LIMITS FOR EACH PGU*

Pollutant	Emissions (lb/hr)
PM10	16.3

*This emission limits applies to loads greater than 50% (data provided by General Electric and Duke/Fluor-Daniel does not include condensable particulates.)

A visual opacity limit of five percent shall also apply to each stack.

EPA Reference Method 201A shall determine initial compliance with the particulate limits. Annual source testing must be conducted to demonstrate continued compliance.

Compliance with the opacity standard shall be determined by use of Ecology Method 9 based on 6 continuous minutes of observer readings.

2.2.6 SULFUR TRIOXIDE AND SULFURIC ACID

The Satsop CT Project estimates that the majority of the sulfur dioxide will oxidize to sulfur trioxide as a combined result of turbine combustion process and the post-oxidation catalyst system. The Satsop CT Project proposes, **and EFSEC agrees, that using pipeline quality natural gas constitutes BACT for sulfur dioxide and sulfur trioxide control**. Virtually all the sulfur trioxide should hydrolyze by reaction with water vapor in the exhaust gas to sulfuric acid or with excess ammonia to ammonia sulfate. Sulfuric acid emissions from each PGU's stack shall not exceed 1.3 lb/hr or 31.2 lb/day.

Duke Energy is planning to install sulfur removal equipment at the Satsop CT Project site if the total sulfur content of pipeline quality natural gas exceeds 0.2 gr/100dscf threatening Satsop CT Project ability to achieve the proposed permit limitations. Ammonium Sulfate emissions from each PGU's stack shall not exceed 1.7 lb/hr or 41.0 lb/day.

Monitoring Requirements: There has been considerable fluctuation in sulfur content in pipeline quality natural gas. As result, EFSEC requires that the Satsop CT Project conduct source testing for sulfuric acid mist once per month for the first year of operation at each PGU exhaust stack. If test results demonstrate compliance with permit conditions, subsequent stack testing for sulfuric acid can be reduced to once per year. **EFESC agrees that the use of pipeline quality natural gas is BACT for sulfuric acid.** Sulfuric acid emissions from each PGU exhaust stack shall not exceed 1.3 lb/hr or 31.2 lb/day

2.3 BACT FOR COOLING TOWERS:

Wet cooling towers utilize air passage through the cooling water to cool the water for reuse. This direct contact between the cooling water and the air passing through the tower results in entrainment of some of the liquid water in the air stream. The entrained water is carried out of the tower as "drift" droplets. The drift droplets generally contain the same chemical impurities and additives as the water circulating through the tower. These impurities and additives can be converted to airborne emissions. This results in 4.5 ton/yr of particulate.

Satsop CT Project proposes, and **EFSEC agrees,** that installation and operation of drift eliminators constitute BACT for the cooling tower.

2.4. BACT FOR AUXILIARY BOILER

EFSEC agrees with the Satsop CT Project evaluation and determines BACT to be a combination of Flue Gas Recirculation and low NO_x burners for controlling NO_x emissions. The hours of operation at the auxiliary boiler will be limited to 500 hours per year. The proposed BACT emission limit for NO_x is shown in Table 7. Other pollutants that will be emitted by the auxiliary boiler include 147 lb/yr of PM, 235 lb/yr of VOC and 14.5 lb/yr sulfur dioxide.

TABLE 7

PROPOSED BACT NO_x EMISSION LIMITS FOR THE AUXILIARY BOILER*

Pollutant	Emissions (ppmvd) at 15% O2	Emissions (lb/hr)
NOx	30	1.03

*Based on 100% load.

2.5 OPERATING SCHEDULE:

The Satsop CT facility will operate up to 24 hours per day, up to 365 days per year. Duct firing will be limited to a maximum of 6760 hours for each power generation unit per year. The auxiliary boiler will be limited to 500 hours of operation each year. The proposed operating scenarios are outlined in Table 8.

TABLE 8
RANGE OF OPERATING SCENARIOS FOR THE SATSOP CT PROJECT

Annual hours of operation for each PGU with Duct Firing	Annual hours of operation for each PGU without Duct Firing	Total hours per year for each PGU	Total Duct Firing for Both PGUs Annually	Tons of PM Annually for Facility
3360	5400	8760	6720	115
4500*	3582	8082	9000	115
5700*	1658	7358	11400	115
6760*	0	6760	13520	115

*A potential situation that could arise with the above operating scenarios is that the project could consume all the allowable emissions, (particularly PM and NO_x) before a 365 day accounting cycle was completed. This could result in a potential situation where the facility would be forced to remain idle up to three months per year.

3. AMBIENT AIR QUALITY ANALYSIS

3.1 REGULATED POLLUTANTS

PSD rules require an ambient air quality impacts assessment (40 CFR Part 52.21) from any facility emitting pollutants in significant quantities. Limiting increases in ambient concentrations to maximum allowable increments prevents significant deterioration of air quality.

Ambient Impact Analysis indicates that all regulated pollutant emissions are below ambient air quality standards established to protect human health and welfare, and no significant ambient air quality impact will result from the proposed Satsop CT plant emissions.

3.2 TOXIC AIR POLLUTANTS

EFSEC requires an ambient air quality analysis of toxic air pollutants (TAP) emissions in accordance with WAC 173-460 "Controls for New Sources of Toxic Air Pollutants". All TAPs that will be emitted from the turbines were analyzed. Ammonia, acrolein, acetaldehyde, benzene, beryllium, formaldehyde, arsenic, cadmium, polyaromatic hydrocarbons, chromium, hexavalent chromium, nickel, and lead were established and modeled to determine the maximum ambient concentrations. These maximum ambient concentrations were then compared to the respective acceptable source impact levels (ASIL).

Ambient concentrations of all of these TAPs were found to be below the ASILs contained in WAC 173-460. Therefore, no adverse health impacts are expected to occur due to TAPs emitted from the Satsop CT facility and no further analysis of BACT for the toxic air pollutants is required. **EFSEC determines** that BACT for the toxic pollutants for the Satsop CT Project is SCR, CO-catalytic combustion, good combustion practice and use of natural gas as fuel.

3.3 AMMONIA EMISSIONS

Ammonia emissions from the Satsop CT Project deserve special discussion. Ammonia is a TAP defined in WAC 173-460. Ammonia is released from the SCR process because a slight excess is required to force NO_x emissions down to the desired levels. The excess ammonia is called "ammonia slip". SCR manufacturers guarantee that this leakage of unused ammonia will be less than 5.0 ppmvd. At 5 ppmdv, the maximum modeled ammonia concentration out-side the boundary of the Satsop CT Project is about 3.0 micro grams per cubic meter. This concentration of ammonia is 97% below the national standards.

EFSEC concludes that 5.0 ppmvd ammonia emission limits for the Satsop CT Project does not threaten human health. Nonetheless, there is one more consideration relative to ammonia as a TAP. Prior to the commercialization of the SCONOx process, SCR was unquestionably BACT. As discussed in this fact sheet, SCONOx has not passed the economic test of BACT cost effectiveness for criteria pollutant control for the Satsop CT Project. However, because the use of SCONOx would eliminate ammonia emissions, Chapter 173-460 WAC requires that SCONOx be considered as a possibility for BACT for TAPs (T-BACT). By substituting a reasonable BACT cost effectiveness for VOC reduction for the calculation outlined in this fact sheet, SCONOx cost can be applied to evaluate the cost effectiveness for ammonia. For the purpose of this exercise, we impose a $2531 per ton ceiling for the

VOC and extra CO reduction. This leaves an annual cost per turbine of $2,557,295 For SCONOx that can be applied as an ammonia reduction cost. For the 148 ton per year ammonia reduction per turbine, this is $10,740/ton. Since there is no apparent health risk from the ammonia emissions, this is not a justifiable control cost. Consequently, **EFSEC concludes with the Satsop CT Project's evaluation and determines T-BACT for ammonia emissions is SCR with an emission limit of 5.0 ppmdv.**

Ammonia is a Washington State toxic air pollutant (TAP) by itself, and also combines with hydrated sulfur and nitrogen oxides to form the corresponding salts. Environmentally these salts are particulates that contribute to visible haze. Inevitably, these salts deposit in soils, and may cause excessive nitrogenous enrichment. This is discussed further in this fact sheet.

4. AIR QUALITY RELATED VALUES

4.1 NATIONAL AMBIENT AIR QUALITY STANDARDS

The United States Environmental Protection Agency (EPA) and the Washington Department of Ecology (Ecology) have established national and Washington ambient air quality standards (NAAQS and WAAQS, respectively). "Primary" standards apply to populated areas (Class II areas), and are designed to protect human health and safety. "Secondary" standards apply to sensitive areas (Class I areas), and are designed to protect soils and vegetation. The proposed project is required to evaluate potential visibility impairment to Class I areas located within a radius of 100 miles from the new source. Class I areas include National Parks and Wilderness Areas, which are areas where air quality is afforded a higher degree of protection than other areas. Four Class I areas fall within a 100 miles radius of the proposed site: Olympic National Park, Mt. Rainier National Park, Goat Rocks Wilderness Area, and Alpine Lakes Wilderness Area, all of which are in the State of Washington.

Following proposed revisions to Ecology's guidance on visibility and other "regional" modeling analysis, the modeling domain for this project also includes Pasayten Wilderness, Glacier Peak Wilderness, Mt. Hood Wilderness, Mt. Baker Wilderness, and the Columbia River Gorge National Scenic Area.

Potential impacts are tested by modeling the predicted increase in ambient concentrations of the pollutants (NOx, CO, and SOx) emitted by the new source, and comparing them to a maximum that is allowed (Class I or II increment). EPA has established no significant ambient impact concentration for ozone (VOCs).

4.2 CLASS I AREA IMPACTS

The PSD regulations require an evaluation of the effects of the anticipated emissions on visibility from any class I area and the impact of emissions on soils and vegetation. Representative meteorological data was obtained from a air monitoring station located in the Satsop Power Plant property boundary. Other data used included MM5 regional air quality data base. Impact were evaluated for the five established Class I areas within 160 kilometer (100 miles) of the proposed site were evaluated. At the recommendation of the federal land managers, Satsop CT Project used CALPUFF which is a non-steady - state Lagrangian Gaussian puff model containing modules for complex terrain effects, overwater, transport, coastal interaction effects, building downwash, wet and dry removal, and simple chemical transport.

4.2.1 VISIBILITY

The Satsop CT Project used an advanced modeling (noted above) process to demonstrate that there will be no significant visibility impacts on Class 1 areas resulting from the proposed Satsop CT emissions. **EFSEC concludes that the Satsop CT Project is unlikely to have a significant impact on visibility in Class I areas.**

4.2.2 DEPOSITION

Ozone, nitrogen oxides, nitrates and sulfur dioxide fallout have the potential to impact flora and fauna in the area surrounding an emissions source. The impacts of the pollutants from the Satsop CT project on soils, animals, surface water, and vegetation were evaluated (noted above). None of the listed pollutants will cause an exceedence of the US Forest Service guidance defining potential adverse impacts. The nitrate and nitrite deposition from the Satsop CT facility plus existing background deposition rates will not exceed the initial threshold for concern. **EFSEC concludes that the Satsop CT Project is unlikely to have a significant impact on vegetation, soil, and aquatic resources in Class I or Class II.**

5. OTHER AIR QUALITY IMPACTS

Acid Rain Provisions: Title IV of the Clean Air Act Amendments of 1990 requires all facilities with gas turbines rated with an electric output greater than 25MW which provides at least one third of the output to a distribution system must comply with the 40 CFR Part 75 regulations. The Satsop CT Project will be required to monitor NOx, SO2.O2, and flow rate. The continuous emission monitors required under the NSPS regulations are similar to those required by 40 CFR Part 75; however, the accuracy limits during the annual relative accuracy test audits are more stringent.

During the construction phase of the project construction workers will be employed, requiring temporary housing and producing motor vehicle emissions during their daily commute to the work site and from the operation of heavy and other internal combustion engine powered equipment at the project site. During construction, there is the possibility of generation of wind blown dust from earth moving operations and vehicle and equipment operation of unpaved areas of the project site or access roads. This dust is not subject to PSD or New Source permitting, and has been evaluated during the SEPA process.

It is expected that the majority of employees will come from the local area.

6. AIR POLLUTION CONTROL REGULATORY REQUIREMENTS

This project is subject to the following federal regulations:

Prevention of Significant Deterioration	40 CFR 52.21
New Source Performance Standards	40 CFR 60, Subpart GG
New Source Performance Standards	40 CFR 60, Subpart Da
New Source Performance Standards, Quality Assurance Procedures	40 CFR 60, Appendix F
New Source Performance Standards, Performance Specifications	40 CFR 60, Appendix B
Permitting	40 CFR 72
Emissions Monitoring and Permitting	40 CFR 75
NO_x Requirements	40 CFR 76
Sulfur content of natural gas to be monitored	40 CFR 60.334(b)(2)

The source is subject to the following state regulations:

General and Operating Permit Regulations for Air Polluting Sources	463-39 WAC
General Regulations for Air Pollution Sources	173-400 WAC
Operating Permit Regulation	173-401 WAC
Controls For New Sources of Toxic Air Pollutants	173-460 WAC

ENERGY FACILITY SITE EVALUATION COUNCIL
P.O. BOX 43172
OLYMPIA, WASHINGTON 98504-3172

IN THE MATTER OF:	]	**NO. EFSEC/2001-01**
Satsop Combustion Turbine Project	]	
Electrical Generating Facility	]	**Preliminary Approval**
Elma, Washington	]	**NOTICE OF CONSTRUCTION**
	]	**AND PREVENTION OF**
	]	**SIGNIFICANT DETERIORATION**

Pursuant to the Energy Facility Site Evaluation Council (EFSEC) Permit Regulations for Air Pollution Sources (Washington Administrative Code 463-39), regulation for air permit applications (Washington Administrative Code 463-42-385), the Washington Department of Ecology (Ecology) regulations for new source review (Washington Administrative Code 173-400-110 and Chapter 174-460 WAC), the federal Prevention of Significant Deterioration regulations (40 CFR 52.21), and based upon the complete Notice of Construction Application (NOC), submitted by Duke Energy Grays Harbor, LLC., and Energy Northwest on April 23, 2001, the Energy Facility Site Evaluation Council Resolution No. 298 dated April 13, 2001, the Administrative Order on Consent, Docket No. CAA-10-2001-0097, between the Satsop CT Project and the U.S. Environmental Protection Agency, Region 10, dated March 30, 2001, and the technical analysis performed by Ecology for EFSEC, EFSEC now finds the following:

FINDINGS

1. Duke Energy Grays Harbor, LLC., and Energy Northwest (jointly "Duke Energy") have applied to construct the Satsop Combustion Turbine Project which is to be located near Elma, Washington. The proposed 650 megawatt (MW) project consists of two (2) separate, combined cycle, natural gas fired power generation facilities, each rated at 175 Megawatts (MW) and one steam turbine generator (STG) rated at 300 Megawatts (MW). The project will consist of the following major components:

    1.1. Two General Electric gas combustion turbines (GE 7FA);
    1.2 Two heat recovery steam generators (HRSG) with supplementary duct burners;
    1.3. One steam turbine generator (STG);
    1.4. One auxiliary boiler;
    1.5. One forced draft cooling tower system;

These stationary sources may be built separately or simultaneously. Requirements for timing of separate construction shall be done in accordance with Approval Condition 25. They may be operated independently.

2. Duke Energy's NOC/PSD application for the proposed project was determined to be complete on August 1, 2001, after Ecology's review of additional information submitted by the Duke Energy.

3. The project is subject to permitting requirements under the Federal requirements of 40CFR 52.21 because it is one of 28 listed industries that becomes a "major source," when emitting more than 100 tons per year of any regulated pollutant. The Satsop CT Project has potential to emit significant quantities of nitrogen oxides, carbon monoxide, sulfur dioxide, sulfuric acid mist, particulate matter, and volatile organic compounds above Significant Emission Rate thresholds.

4. The project will use natural gas. No other fuel will be used as backup during periods of natural gas curtailment.

5. The site of the proposed project is within an area that is in attainment with regard to all pollutants regulated by the National Ambient Air Quality Standards (NAAQS) and state air quality standards. The site is approximately 60 kilometers from the nearest Class I Area, Olympic National Park.

6. The project is subject to new source review requirements under Chapter 173-400 WAC, Chapter 173-460 WAC, 40 CFR 52.21, 40 CFR 60.40b, 40 CFR 60.330; to emission monitoring requirements under RCW 70.94, Chapter 173-400 WAC, 40 CFR 60 Appendices A, B, and F, and 40 CFR 75; and to gas fuel monitoring requirements under 40 CFR 60.334(b)(2).

7. Best available control technology (BACT) as required under WAC 173-113(2) and toxic best available control technology (T-BACT) as required under WAC 173-460-040(4) will be used for the control of all air pollutants which will be emitted by the proposed project.

8. The facility will have the potential to emit up to 264 tons per year of oxides of nitrogen (NO_X).

9. The facility will have the potential to emit up to 424 tons per year of carbon monoxide (CO).

10. The facility will have the potential to emit up to 10 tons per year of sulfur dioxide (SO_2).

11. The facility will have the potential to emit up to 80 tons per year of volatile organic compounds (VOCs).

12. The facility will have the potential to emit up to 115 tons per year of filterable particulate matter less than or equal to 10 microns aerodynamic equivalent diameter (PM_{10}).

13. The facility will have the potential to emit up to 11.4 tons per year of sulfuric acid mist.

14. The facility will have the potential to emit up to 121 tons per year of ammonia.

15. Allowable emissions from the new emissions units will not cause or contribute to air pollution in violation of:

    15.1. Any state or national ambient air quality standard;
    15.2. Any applicable maximum allowable increase (PSD increment) over the baseline ambient concentration.

16. Ambient Impact Analysis indicates that there will be no significant impacts resulting from pollutant deposition on soils and vegetation in either the Mt. Rainier or Olympic National Parks.

17. Ambient Impact Analysis indicates that during natural gas firing, no significant degradation of regional visibility or vistas from National Parks will occur due to this project.

18. No significant effect on industrial, commercial, or residential growth in the Elma area is anticipated due to the project.

19. EFSEC finds that all requirements for new source review (NSR) and PSD are satisfied and that as approved below, the new emissions units comply with all applicable federal new source performance standards. Approval of the NOC application is granted subject to the following conditions.

APPROVAL CONDITIONS

1. The combustion turbines (PGUs) shall be fueled only by pipeline quality natural gas.

2. NO_X emissions from each power generating unit (PGU) exhaust stack of the project shall not exceed of the following:
   2.1. 21.7 pounds per hour (1-hour average) with duct firing;
   2.2. 16.8 pounds per hour (1-hour average) without duct firing;
   2.3. 2.5 ppmvd (parts per million on a dry volumetric basis) over (1-hr average) when corrected to 15.0 percent oxygen (O2).

   Initial compliance shall be determined in accordance with 40 CFR Subpart GG and EPA Reference Method 20, except that the instrument span shall be set between zero and 25 ppm. NO_X and O_2 concentrations shall be measured and recorded by a continuous emission monitoring system (CEMS) which meets the requirements of Approval Condition 17.1 Such CEMS shall be used to determine compliance with this Condition.

3. Ammonia (free NH3 and ammonium sulfate measured as NH3) emissions from each PGU exhaust stack of the project shall not exceed 5.0 ppmvd on a (1-hour average) corrected to 15.0 percent oxygen. NH3 emissions from each PGU exhaust stack shall not exceed 16.1 lb/hr (1-hour average).

Initial compliance for each PGU shall be determined by Bay Area Air Quality Management District Source Test Procedure ST-1B, "Ammonia, Integrated Sampling," or an equivalent method approved in advance by EFSEC. NH_3 emissions from each PGU exhaust stack shall be measured and recorded by a continuous emission monitoring system (CEMS) which meets the requirements of Approval Condition 17.2. Duke Energy may propose alternative means for continuous assessment and reporting of NH_3 emissions for approval by the Council. Any proposed alternative NH_3 reporting shall be at a minimum equivalent to a continuous emission monitoring system (CEMS) which meets the requirements of Condition 17.

The SCR catalyst shall be repaired or replaced at the next scheduled outage following a time period when ammonia slip can no longer be maintained at or below 4.5 ppmvd corrected to 15.0 percent oxygen. The outage shall be no later than 12 months after ammonia slip exceeds 4.5 ppmvd corrected to 15.0 percent oxygen. The permit limitations outlined in this section shall not apply to startup, shutdown and scheduled maintenance conditions.

4. CO emissions from each PGU exhaust stack of the project shall not exceed 2 ppmvd corrected to 15.0 percent oxygen and 10.6 lb/hr at 100% load.

CO emissions from each auxiliary boiler shall not exceed 50.0 ppmvd (1- hour average) corrected to 3.0 percent oxygen, and 1.07 lb/hr.

Initial compliance for each PGU and boiler shall be determined by EPA Reference Method 10 or an equivalent method agreed to in advance by the EFSEC. The span and linearity calibration gas concentrations in Method 10 shall be appropriate to the CO concentration limits specified in this condition. CO emissions from each PGU exhaust stack shall be measured and recorded by a CEMS which meets the requirements of Approval Condition 17.3. Such CEMS shall be used to determine compliance with this Condition.

5. SO_2 emissions from each PGU exhaust stack shall not exceed 0.11 ppmvd over a one hour average when corrected to 15.0 percent oxygen. SO2 emissions from each PGU exhaust stack shall not exceed 1.3 pounds per hour (1-hour average). Sulfur dioxide from auxiliary boiler exhaust stack shall not exceed 0.03 lb/hr (1-hour average).

Initial compliance for each PGU and boiler shall be determined by EPA Reference Method 8, or an equivalent method approved in advance by EFSEC. Duke Energy shall conduct source testing for sulfur dioxide once per month for the first year of operation at each PGU exhaust stack. If test results demonstrate compliance with the permit conditions, subsequent stack testing for sulfur dioxide can be reduced to once per year. Duke Energy shall report to EFSEC on a monthly basis the quantity and average sulfur content of pipeline quality natural gas burned at each PGU unit as substantiated by purchase records and vendor's report. Fuel sulfur determination shall follow procedures outlined in 40 CFR 60.335(d) and (e) or an alternative method approved by EPA and submitted to EFSEC.

6. Sulfuric acid (H_2SO_4) emissions from each PGU exhaust stack shall not exceed 1.3 lb/hr. Initial compliance with the sulfuric acid emissions limits shall be determined by EPA Reference Method 8, or an equivalent method approved by EFSEC. Duke Energy shall conduct source testing for sulfuric acid mist once per month for the first year of operation at each exhaust stack. If test results demonstrate compliance with the permit conditions, subsequent stack testing for sulfuric acid mist can be reduced to once per year.

7. Volatile organic compound emissions (VOCs) from each PGU exhaust stack shall not exceed 8.4 pounds per hour (1-hour average) and VOC emissions from auxiliary boiler shall not exceed 0.469 pounds per hour (1-hour average).

Initial compliance for each PGU and boiler shall be determined by EPA Reference Method 25A or 25B, or an equivalent method agreed to in advance by EFSEC.

8. PM10 emissions from each PGU exhaust stack shall not exceed 391.2 pounds per day (filterable

only) PM10 emissions from each PGU exhaust stack shall not exceed 0.0025 gr/dscf. PM10 emissions from auxiliary boiler exhaust stack shall not exceed 7.0 pounds per day.

Initial compliance for each PGU and the boiler (exhaust stack) shall be determined by either EPA Reference Methods 5, 201, or 201A, or an equivalent method agreed to in advance by EFSEC. In conjunction with the above test, EPA Reference method 202 will also be conducted and the results reported separately.

9. Opacity from each PGU exhaust stack of the project shall not exceed 5 percent over a six minute average as measured by EPA Reference Method 9, or an equivalent method approved in advanced by EFSEC. A certified opacity reader shall read and record the opacity daily if Method 9 is used.

10. With the exception of PM_{10}, SO_2, H_2SO_4, NO_X, CO, and VOCs, the net emissions increase of any pollutant regulated under the Federal Clean Air Act shall be less than the significant levels in 40 CFR 52.21(b)(23)(i).

11. Plantwide emissions shall not exceed the following on an annual total rolled monthly:

PLANTWIDE EMISSIONS*

Pollutant	PGU PER STACK tons/yr	Auxiliary Boiler Tons/yr	Cooling Tower Tons/yr	Total Potential To emit tons/yr
NOx	132	0.26	--	264
SO2	5.0	0.008	--	10
H2SO4	5.7	--	--	11.4
PM	55.2	0.07	4.51	115
CO	212	0.27	--	424
VOC	40	0.12	--	80

* Includes the excess emissions from startup and shutdown events.

12 The number of startup and shutdown shall be limited to 130 events for both PGU units. Emissions resulting from these startup and shutdown events shall be considered and reported in accordance with approval conditions outlined below. The following conditions apply to startup and shutdown periods. The startup period ends when the earlier of the two operating events occurs:

12.1. The proper operating temperature of oxidation and SCR catalysts has been achieved; or

12.2. 2 hours average per turbine have elapsed since fuel was first combusted in the turbine.

The proper operating temperature of the oxidation and SCR catalysts shall be determined from the Manufacturer's design specifications and must be reported in writing to EFSEC before commercial operation of the combustion turbines. The number of startup and shutdown are limited to 130 events per year, with a maximum of two startups per turbine per 24 hour period. Compliance with short-term emission limits (during startup and shutdown periods) shall be determined using manufacturer's emission factors or source test data. Where source test data and Manufacturer's emission factors conflict, source test data shall be used to determine compliance.

Compliance with the plantwide annual emissions per PGU exhaust stack shall be determined using a combination of source test data, CEM data and emission factors. Annual emissions per PGU shall include emissions generated during startup and shutdown periods. Source testing is to be conducted at 100% load with duct firing. The following emission factors (assuming full load) can be used for calculating the emissions generated during startup and shutdown periods until new source test data is developed by Duke Energy and approved by EFSEC.

Pollutant	Emission Factor (both turbines)
Nitrogen oxides	1536 lb/4-hr (average)
Carbon monoxide	5288 lb/4-hr (average)
Volatile organic compounds	354 lb/4-hr (average)

13. Duct firing system: Duct firing shall not exceed 6760 hours per year within each power generating unit (each combustion turbine). A totalizer or metering device will be installed to record hours of operation for each duct firing system, or an equivalent method approved in advance by EFSEC.

14. Within 180 days after initial start-up of each combustion turbine, Satsop Generation Facility shall conduct performance tests for NO_X, ammonia, SO_2, opacity, VOC, CO, PM_{10} and H_2SO_4 on each PGU and boiler, to be performed by an independent testing firm. A test plan shall be submitted to EFSEC for approval at least 30 days prior to the testing. Initial start-up for each combustion turbine is defined as the time when the first electricity from each PGU and the associated steam turbine generator is delivered to the electrical power grid.

15 Sampling ports and platforms shall be provided on each stack, after the final pollution control device. The ports shall meet the requirements of 40 CFR, Part 60, Appendix A, Method 20.

16. Adequate permanent and safe access to the test ports shall be provided. Other arrangements may be acceptable if approved by EFSEC prior to installation.

17. Continuous Emission Monitoring Systems

17.1 CEMS for NO_X, and O_2 compliance shall meet the requirements contained in 40 CFR 75, Emissions Monitoring.

17.2 CEMS for ammonia shall meet the requirements contained in 40 CFR, Part 63, Appendix A and 40 CFR, Part 60, Appendix F, Quality Assurance Procedures, or other EFSEC- approved performance specifications and quality assurance procedures.

17.3 Continuous emission monitoring systems (CEMS) for CO, shall, at a minimum meet the requirements contained in 40 CFR, Part 60, Appendix B, Performance Specifications and in 40 CFR, Part 60, Appendix F, Quality Assurance Procedures.

18. Compliance testing shall be performed for PM_{10} and VOCs from each PGU and boiler exhaust stack annually for the first three years following initial startup, and once every 3 years thereafter as long as compliance continues to be demonstrated. Source testing for these parameters is to coincide with the Relative Accuracy Test Audit required for each installed CEMS.

19. CEMS and process data shall be reported in written (or electronic if permitted by the EFSEC) form to the authorized representative of EFSEC and to the EPA Region X Office of Air Quality monthly (unless a different testing and reporting schedule has been approved by EFSEC) within thirty days of the end of each calendar month.

20. The format of the reporting described in Condition 19 shall match that required by EPA for Demonstrating compliance with the Title IV Acid Rain program reporting requirements. Pollutants not covered by that format shall be reported in a format approved by EFSEC that shall include at least the following:

    20.1 Process or control equipment operating parameters.
    20.2 The hourly maximum and average concentration, in the units of the standards, for each pollutant monitored.
    20.3 The duration and nature of any monitor down-time.
    20.4 Results of any monitor audits or accuracy checks.
    20.5 Results of any required stack tests.
    20.6 The above data shall be retained at the Satsop CT Project site for a period of five years.

21. For each occurrence of monitored emissions in excess of the standard, the monthly emissions report (per Approval Condition 19 and 20) shall include the following:

    21.1 For parameters subject to monitoring and reporting under the Title IV, Acid Rain program, the reporting requirements in that program shall govern excess emissions report content.

21.2 For all other pollutants:

21.2.1 The time of the occurrence.

21.2.2 Magnitude of the emission or process parameters excess

21.2.3 The duration of the excess.

21.2.4 The probable cause.

21.2.5 Corrective actions taken or planned.

21.2.6 Any other agency contacted.

22. Operating and maintenance manuals for all equipment that has the potential to affect emissions to the atmosphere shall be developed and followed. Copies of the manuals shall be available to EFSEC or the authorized representative of EFSEC. Emissions that result from a failure to follow the requirements of the manuals may be considered proof that the equipment was not properly operated and maintained.

23. Operation of the equipment that has the potential to affect the quantity and nature of emissions to the atmosphere must be conducted in compliance with all data and specifications submitted as part of the PSD/NOC application unless otherwise approved by EFSEC.

24. This approval shall become void if construction of the project is not commenced within 18 months after receipt of final approval, or if construction of the facility is discontinued for a period of 18 months, unless EFSEC extends the 18 month period upon a satisfactory showing that an extension is justified , pursuant to 40 CFR 52.1 (r) (2) and applicable EPA guidance.

25. Any activity which is undertaken by Duke Energy or others, in a manner which is inconsistent with the application and this determination, shall be subject to EFSEC enforcement under applicable regulations. Nothing in this determination shall be construed so as to relieve Duke Energy of its obligations under any state, local, or federal laws or regulations.

26. Duke Energy shall notify EFSEC in writing at least thirty days prior to start-up of the project.

27. Access to the source by EFSEC, the authorized representative of EFSEC, or the U.S. Environmental Protection Agency (EPA), shall be permitted upon request for the purpose of compliance assurance inspections. Failure to allow access is grounds for action under the Federal Clean Air Act or the Washington Clean Air Act.

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